MODELING OF WELLBORE FLOW WITHIN
GEOTHERMAL RESERVOIR SIMULATIONS AT FIELD SCALE

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ABSTRACT

Geothermal field exploitation is achieved by a wellhead control of well discharge to satisfy the constraints imposed by the surface steam-gathering system. Modern simulation approaches consist of coupled fluid dynamic modeling of the reservoir, the wellbores, and the surface steam-gathering system for a comprehensive evaluation of the entire production system. The conventional approach describes the fluid extraction by imposing a suitable bottomhole pressure and using a deliverability model to compute the production rate. While more realistic than previous approaches, new approaches have the disadvantage of coupling different codes, each one with specific modeling issues that may require longer simulation times. An improvement on the conventional approach is presented here, based on a modification of the well on deliverability method in the presence of multiple feed zones. Wellbore flow is solved in a more rigorous way between wellbore nodes, and can be extended up to the surface, allowing for modeling of reservoir exploitation with wells producing at a fixed wellhead pressure. The approach has been developed within the TOUGH2 V.2.0 numerical reservoir simulator and is presently limited to geothermal fluids that may be properly modeled using pure water.

INTRODUCTION

Exploitation of geothermal fields is achieved with the extraction and reinjection of fluids through production and reinjection wells. Thus, the realistic modeling of wellbore flow in geothermal field simulation is very important for obtaining reliable results. Field exploitation is achieved by wellhead control of well production, which needs to satisfy the constraints imposed by the separation pressure, the pressure drops in the surface steam-gathering system, and the turbine inlet pressure. Modern approaches to geothermal reservoir simulation consist of coupled fluid dynamic modeling of the reservoir and wellbores (Murray and Gunn, 1993; Hadgu et al., 1995; Bhat et al., 2005; Pan et al., 2011), including the surface steam-gathering system (Tokita et al., 2005; Butler and Enedy, 2010; Blöcher et al. 2010) for a comprehensive evaluation of the entire production system. On the other hand, the conventional approach handles fluid extraction by imposing a suitable bottomhole pressure and using a deliverability model to compute the production rate. The new approach has the disadvantage of coupling different codes, each one with specific modeling issues, which may require longer simulation times than conventional simulations. The older approach is based on a rough representation of wellbore-reservoir coupling that may significantly alter the description of reservoir behavior under exploitation.

A modification of the conventional approach is here presented, in order to obtain a satisfactory description of a coupled wellbore-reservoir system, preserving a computational speed compatible with simulations of geothermal reservoirs at the field scale and for the exploitation times of interest. The conventional well on deliverability method in the presence of multiple feed zones is modified by solving (in a rigorous way) the flow between wellbore nodes accounting for gravitational, frictional, and acceleration pressure drops in the momentum conservation equation—while potential, kinetics, and heat-transfer contributions are considered in the energy conservation equation. Wellbore flow simulation can be extended up to the surface, allowing the modeler to capture reservoir exploitation with wells producing at fixed wellhead pressure. The approach, which has been developed within the TOUGH2 V.2.0 reservoir

simulator, is presently limited to geothermal fluids that may be properly modeled using pure water.

OPTIONS AVAILABLE IN TOUGH2

TOUGH2 V.2 implements two basic options for the treatment of production wells (Pruess et al., 1999): (i) a wellbore on deliverability approach (DELV), extended to simulating wells producing from multiple feed points; and (ii) the so-called F-type option, in which the bottomhole pressure (BHP) of a wellbore on deliverability is not held constant, as in the conventional DELV option, but is determined by looking at a pre-calculated table of BHP as a function of rate and enthalpy. The table is computed using a wellbore flow simulator for a given well completion and fixed wellhead pressure (WHP).

DELV option

With the DELV option, the production rate of generic phase β is determined as a function of the wellblock mobility and the pressure difference between wellblock (P_β) and wellbore (P_{wb}), proportionally to a productivity index PI (Pruess et al., 1999):

$$q_\beta = \frac{k_{r\beta}}{\mu_\beta} \rho_\beta \, PI(P_\beta - P_{wb}) \qquad (1)$$

When a well is completed over multiple permeable layers, the wellbore pressure depends on the contribution of different feed points and should be computed by solving mass-, momentum-, and energy-balance equations describing the wellbore flow. In TOUGH2, this is accomplished in a simplified way by using an approach based on Coats (1977), originally developed for hydrocarbon wells, in which a gas and an oil phase of low mutual solubility are flowing. The main assumptions made in solving wellbore flow are:

i. The volumetric rate from each feed point is determined assuming the wellbore pressure were zero;

ii. At each node, volumetric rates from wellbore and feed points are added;

iii. The flowing density at each node is computed using phase flowing rates determined as per point (ii), and phase densities equal to those computed at wellblock conditions.

The above procedure provides a reasonable calculation of wellbore pressure profiles under flowing conditions only in the presence of single-phase liquid conditions: the gravitational contribution is predominant over friction and acceleration contributions, which are completely neglected. However, they can be considerable in both two-phase and single-gas flowing conditions, making the calculation of feed point rate unreliable. Moreover, if one wellblock element has single-phase conditions, the density of the nonexisting phase is missing, and the calculation of flowing density at wellbore node is completely erroneous.

F-type option

The so-called F-type option was introduced in TOUGH2 V.2.0 (Pruess et al., 1999) by replicating the approach used by Murray and Gunn (1993) for the TETRAD simulator. Fluid is extracted from a wellblock element in analogy with the DELV option (Eq. 1) in which the wellbore pressure is not held constant along the simulation, but determined at each time step as a function of rate and enthalpy. In practice, wellbore flow for a specific well completion and a fixed WHP is solved using a wellbore simulator. The wellbore pressure needed to have the desired WHP is given through a table as a function of rate and fluid enthalpy. TOUGH2 determines the BHP, rate, and enthalpy using an iterative procedure in which the capillary pressure in the wellblock element is neglected. The main limitation of this option is that it is applicable to a single feed point only, while most geothermal wells produce from multiple distinct feed points.

F-TYPE OPTION EXTENDED TO MULTIPLE FEED POINTS

The first step towards a more realistic simulation of coupled wellbore and reservoir flow within TOUGH2 has been made by coupling the F-type and DELV options. An inactive dummy element is added to the ELEME block for each producing wellbore. An F-type option is activated for each of these dummy elements, in order to read the file containing the tabulated BHP as a function of rate and enthalpy. To couple F-type and DELV, we add the reading of F-type file name in correspondence of the uppermost source of the well on deliverability completed over multi-

ple layers. At the end of a converged time step, subroutine WF is called to determine the BHP as a function of rate and enthalpy at the converged time step. This BHP is then used in subroutine GCOR to calculate the approximate wellbore pressure profile under flowing conditions needed by the DELV option. To avoid oscillations in computed well-production rates and enthalpy, subroutines WF and GCOR are actually called at the end of each completed Newton-Raphson (NR) iteration. The table of BHP values as a function of total rate and mixture enthalpy is computed in one single run using the PROFILI wellbore simulator (Battistelli, 2010). A few checks of flowing pressure profiles computed by TOUGH2 using PROFILI clearly show that neglecting frictional and acceleration pressure drops in the momentum equation and not solving the energy-balance equation lead to unreliable results.

IMPROVEMENT OF SUBROUTINE GCOR

The second step towards a more realistic simulation of coupled wellbore and reservoir flow was the improvement of subroutine GCOR. Within the standard TOUGH2 code (Pruess et al., 1999), GCOR is called once for a completed simulation time step to compute the flowing wellbore pressure profile for each DELV option applied to wells producing from multiple feed points. The pressure profile is then held constant along the NR iterations of the subsequent time step. For a more realistic coupled simulation, subroutine GCOR is called at the beginning of each NR iteration to update the flowing pressure profile used by DELV.

The major change is the complete rewriting of the iteration process used by GCOR to compute the flowing pressure profile, starting from the wellbore pressure assigned for the uppermost wellbore node. This new approach, based on a rigorous solution of wellbore flow, carries the major assumption that wellbore conditions in a field-scale simulation change slowly, so that a steady-state solution can be used within each time step. The approach, starting from the bottom, is as follows:

- Model wellbore flow between two (virtual) well nodes by solving mass-, momentum-, and energy-balance equations.

- Once the wellbore pressure is determined at the upper node, compute the discharge rate and enthalpy from the layer connected to the upper node and then compute new rates, mixture enthalpy, and wellbore temperature after the mixing between well flow and feed point flow. In practice, an isenthalpic flash is solved by knowing total mass, mixture enthalpy, wellbore pressure, and overall composition (for EOSs other than EOS1).

- The above steps are performed starting from the bottom node up to the top node of the wellbore, and they are iteratively repeated until the given wellbore pressure at the top well node is reproduced within a given accuracy.

It must be pointed out that the solution of isenthalpic flash and of wellbore flow is dependent on the EOS module used.

Modeling of wellbore flow

Momentum- and energy-balance equations are written analogously to PROFILI implementation. PROFILI is a steady-state wellbore simulator initially developed (Battistelli et al., 1990) for modeling steady-state flow in geothermal wells producing mixtures of water, NaCl, and a non-condensable gas (NCG), inspired by the work by Barelli et al. (1982). The present PROFILI version uses the EWASG EOS correlations (Battistelli et al., 1997; Battistelli, 2012). Momentum and energy equations are written following approaches for two-phase flow developed for nuclear plant applications by CISE (Lombardi e Ceresa, 1978; Bonfanti et al., 1979) and by CeSNEF (Lombardi e Carsana, 1992). The momentum equation is given by Eq. 2:

$$\frac{dP}{dz} = \tau_{fr} + \tau_{ac} + \tau_{gr} \qquad (2)$$

where τ is the gradient and subscripts *fr*, *ac*, and *gr* stand for friction, acceleration, and gravity, respectively. The energy balance, with respect to the unit mass of fluid, is given by Eq. 3:

$$dh = Q + dE_k + dE_p \qquad (3)$$

where h is the specific enthalpy, Q the heat exchanged with rock formations, and E_k and E_P the kinetic and potential energy, respectively.

With reference to the Barelli et al. (1992) approach, Eq. 2 can be written as follows:

$$\frac{dP}{dz} = \frac{2f\rho u^2}{D} + \frac{d(\rho u^2)}{dz} + \rho g \qquad (4)$$

where f is the Fanning friction factor equal to one fourth of the Darcy-Weisbach (Moody) friction factor, D is wellbore diameter, u is the fluid velocity, g is the acceleration of gravity, and ρ the fluid density.

CeSNEF-2 correlations for two-phase pressure drops are given by Eq. 5, where, f_L and f_G are the Fanning friction factors of liquid and gas phases, determined as if the entire flow rate were liquid or gaseous; f_m is the mixture friction factor; b_L, b_G and b_m are interpolation functions of the mixture dryness fraction x; and A is the well section surface:

$$\frac{dP}{dz} = \frac{2G^2(f_L b_L + f_G b_G + f_m b_m)}{A^2 D \rho_m} + \frac{G^2(1/\rho_m)}{A^2 dz} + \rho_m g \qquad (5)$$

The mixture friction factor is computed using an empirical correlation based on an extensive set of experimental data:
If $L < 30\,C_e$

$$f_m = 0.046 \times 30\,C_e\,L^{-1.25} \qquad (6)$$

else:

$$f_m = 0.046 L^{-0.25} \qquad (7)$$

where the dimensionless parameter C_e is given by:

$$C_e = \frac{\rho_L\,g\,(D - D_0)^2}{\sigma}\frac{\mu_G}{\mu_L} \qquad (8)$$

and:

$$L = \frac{G^2 D}{A^2 \rho_m \sigma}\left(\frac{\mu_G}{\mu_L}\right)^{0.5} \qquad (9)$$

σ and μ are the surface tension and dynamic viscosity, and $D_0 = 0.001$ m. The interpolation functions in Eq. 5 are given by:

$$b_G = x^{(600\,\rho_G/\rho_L)} \qquad (10)$$

$$b_L = (1-x)^{(2\,\rho_L/\rho_G)} \qquad (11)$$

$$b_m = 1 - b_G - b_L \qquad (12)$$

The Fanning friction factor is computed for both laminar and turbulent regimes, as a function of Reynolds number and well wall roughness,

using a correlation from Sze-Foo (1990). Wellbore heat transfer with the surrounding rock formation is computed following Ramey (1975):

$$dq = \frac{2\pi k_T r_w U}{k_T + r_w U f(t_P)}(T_1 - T_e)dz \qquad (13)$$

where k_T is the rock thermal conductivity, r_W is the radius of wellbore, U is the overall heat transfer coefficient of well completion computed according to Whillite (1967), T_1 and T_e are the fluid and formation temperature, and $f(t_p)$ is a dimensionless function of production time t_p computed according to Chiu and Thakur (1991).

VERIFICATION OF WELLBORE FLOW MODELING WITHIN TOUGH2

For verification of this new approach, we constructed a 3D model with sides of 5 km extending from an elevation of +500 masl down to -3000 m asl, with elements of 500 m side and thickness of 100 m. Atmospheric conditions are assigned on the top surface, while lateral sides are closed. Constant heat flux at the bottom boundary, and rock properties are assigned in order to have a conductive heat flow in the upper 500 m (the cap rock), vapor dominated or liquid dominated conditions from 0 m asl down to the bottom. The 3D model is not intended to replicate any natural geothermal system, but is used merely for verification purposes of the new developed algorithm by comparison with wellbore flow simulated by PROFILI. A well completed on 16 layers, from nodes at -1050 m asl to -2550 m asl, was defined. PI of 4.87E-12 m^3 is used on layers open to flow, while zero values are assigned to all layers from which no flow is desired. Several tests were run by assigning the wellbore pressure at the top of well section at -1050 m asl, or directly at wellhead (+500 m asl), and simulating a single feed point at the well bottom, as well as an additional feed at an upper elevation. Single gas, two-phase, and single-liquid conditions were simulated for the bottom feed to test all possible cases. Some of them are discussed here below.

Single Feed Point

A bottom feed at -2550 m asl under single liquid conditions is simulated, with an assigned wellbore pressure of 20 bara at -1050 m asl. Fig. 1 shows the flowing pressure and temperature

(P&T) computed by TOUGH2 (symbols) and PROFILI (lines), while Fig. 2 shows, in addition to pressure, the dryness fraction as well.

P&T profiles computed by TOUGH2 are well reproduced by PROFILI, even if the latter solves wellbore flow with a much finer discretization. A single feed at -2550 m asl under single-gas conditions is simulated with an assigned wellbore pressure of 18 bara at -1050 m asl.
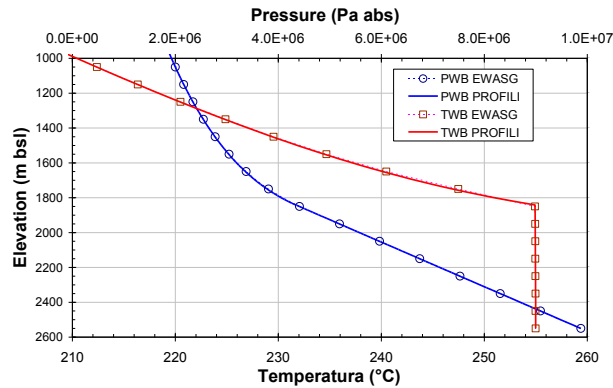

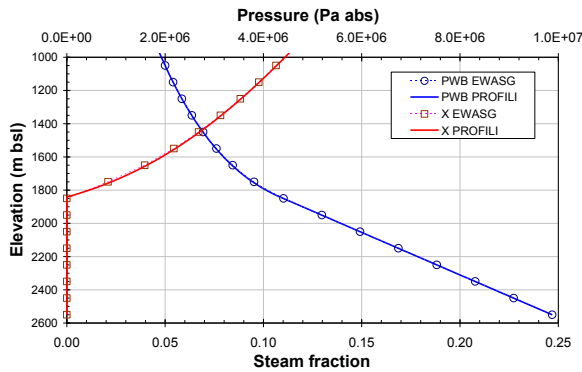Figure 1. Single liquid feed at -2550 m asl. TOUGH2 P&T (symbols) vs PROFILI (lines) results.

Figure 2. Single liquid feed at -2550 m asl. TOUGH2 P & dryness (symbols) vs PROFILI (lines) results.

Fig. 3 shows the flowing P&T computed by TOUGH2 and PROFILI. To show the effect of energy losses, wellbore flow has been computed in both adiabatic and isenthalpic conditions with both TOUGH2 and EWASG. While the reproduction of TOUGH2 results by PROFILI is good for both simulations, Fig. 3 shows that energy losses have a remarkable effect on the temperature profile of a steam-producing well. Avoiding the solution of the energy-balance equation may result in poor reliability of the computed flow temperatures.

A single feed point at -2550 m asl under single-pahse gas conditions is simulated with an assigned wellbore pressure of 10 bara at well head, at the elevation of 500 m asl. Fig. 4 shows a good reproduction of TOUGH2 results by PROFILI.

The wellbore flow was simulated from a single liquid feed point at -2550 m asl up to wellhead at +500 m asl, by assuming a WHP of 10 bara. Fig. 5 shows a good reproduction by PROFILI of flowing P&T computed by TOUGH2. Fig. 6 shows the good reproduction of dryness fraction.
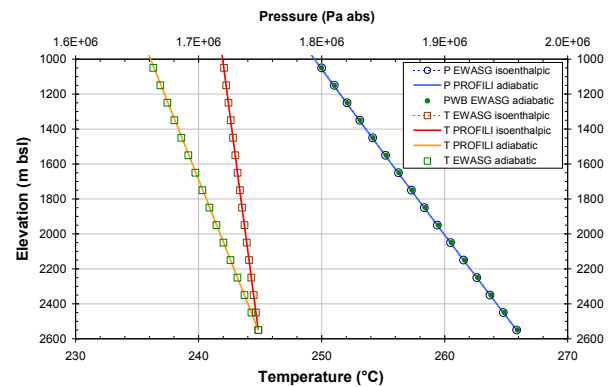

Figure 3. Single gas feed at -2550 m asl. TOUGH2 P&T (symbols) vs PROFILI (lines) results. Adiabatic and isenthalpic simulations are presented.
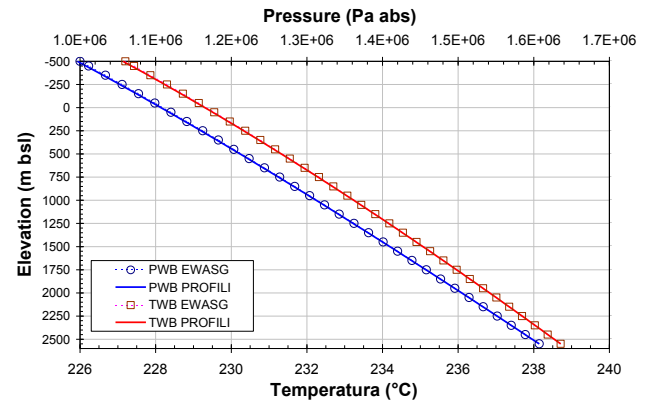

Figure 4. Single gas feed at -2550 m asl. TOUGH2 P&T (symbols) vs PROFILI (lines) results computed up to the well head.
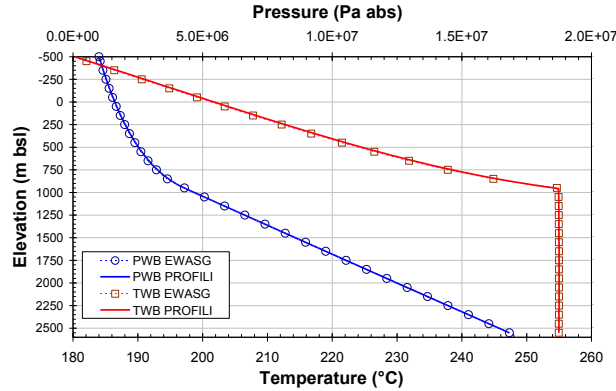
Figure 5. Single liquid feed at -2550 m asl. TOUGH2 P&T (symbols) vs PROFILI (lines) results computed up the wellhead.
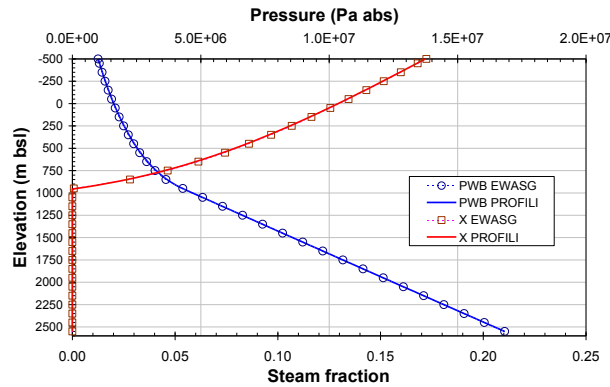

Figure 6. Single liquid feed at -2550 m asl. TOUGH2 P &T dryness (symbols) vs PROFILI (lines) results computed up to the wellhead.

Two Feed Points

Modeling of a single feed enabled us to verify that wellbore flow is properly computed within TOUGH2. Inclusion of an additional upper feed point enabled us to verify that the isenthalpic flash at the mixing between well and reservoir flow is properly solved. In addition to a single-phase liquid feed point at -2550 m asl, an additional feed point of higher enthalpy is added at -1250 m asl. Since PROFILI cannot solve well-bore flow with multiple feeds, the simulation is started from the wellhead considering the total mass discharged. Fig. 6 shows that down to -1250 m asl, PROFILI reproduces both P&T well, while below the upper feed, simulated P&T diverge widely from TOUGH2 results. Fig. 7 suggests how wellbore flow modeling can help in inferring feed zones using flowing P&T logs.
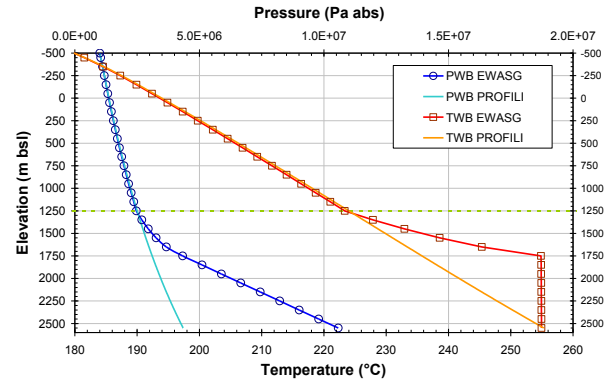

Figure 7. Single liquid feed at -2550 m asl and upper feed at -1250 m asl. TOUGH2 P&T (symbols) vs PROFILI (lines) results computed up to the wellhead.

Fig. 8 shows how PROFILI properly reproduces the flowing enthalpy and dryness fraction down to the upper feed. Note that if two-phase conditions are present where the inflow occurs, the mixing does not have an effect on temperature, because it is constrained by pressure. A change in T gradient is nevertheless visible in Fig. 7. A change in P gradient also occurs, but it is less clear than that of temperature. Dryness fraction and enthalpy are also well reproduced by PROFILI, as shown in Fig. 8.
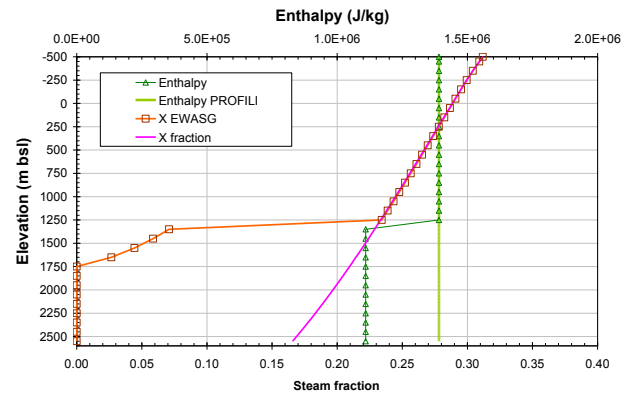

Figure 8. Single liquid feed at -2550 m asl and upper feed at -1250 m asl. TOUGH2 P & dryness (symbols) vs PROFILI (lines) results computed up to the wellhead.

We performed an additional test with a deep feed at -2550 m asl producing two-phase fluid, and an upper feed at -350 m asl producing a higher enthalpy mixture. Wellbore flow is controlled assigning a WHP of 10 bara. Fig. 9 shows TOUGH2 P&T results compared to those

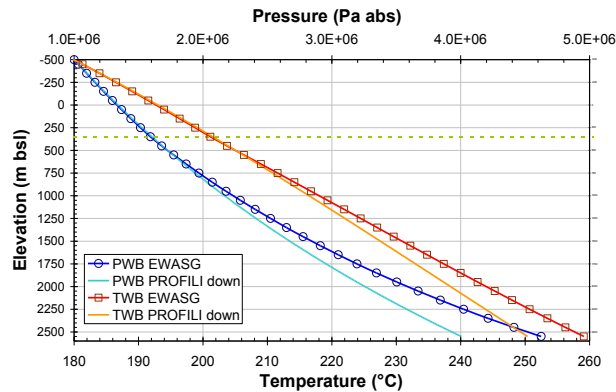simulated by PROFILI starting from the well-head.

Figure 9. Two-phase feed at -2550 m asl and upper feed at -350 m asl. TOUGH2 P&T (symbols) vs PROFILI (lines) results computed up to the wellhead.
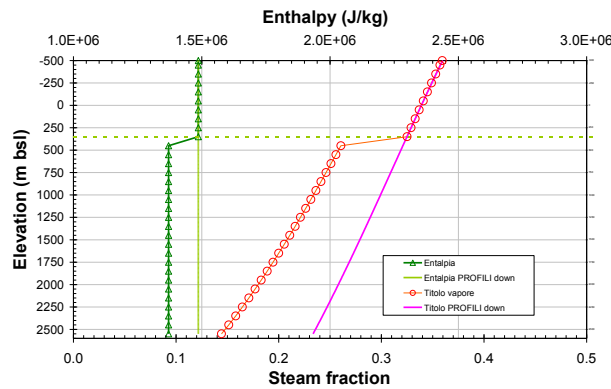

Figure 10. Two-phase feed at -2550 m asl and upper feed at -350 m asl. TOUGH2 P & dryness (symbols) vs PROFILI (lines) results computed up to the wellhead.

P&T are well reproduced down to the upper feed and depart below from TOUGH2 results. Fig. 10 shows the comparison for mixture enthalpy and dryness fraction. This time as well, the upper feed does not produce a step change in flowing temperature, because it is constrained by pressure. Also, P&T gradients are changed marginally by the upper feed and cannot be easily recognized by flowing P&T logs without wellbore flow simulation.

DIRECTIONAL WELLS

Directional wells are being drilled more often in geothermal fields, since they enable the concentration of several wells in clusters, with (1) the reduction of land surface occupation and well pad costs, (2) a reduction in environmental impact, (3) a speeding-up of rig moving operations, (4) a reduction in surface production equipment costs, and (5) an increased chance of intersecting sub-vertical conductive faults. Directional wells can in principle be modeled with the improved GCOR subroutine by providing (within the GENER input block) the cosine value of the angle between the well axis and the vertical direction.

CONTROL OF WELL PRODUCTION BY CHANGING OF WELLHEAD PRESSURE

The developed algorithm allows the user to simulate the coupled wellbore and reservoir flow in wells producing from multiple feeds by assigning the wellhead pressure, if the well description within the DELV option is extended up to the surface. In the present development, the WHP is held constant throughout the simulation. In principle, it could be changed during reservoir exploitation to meet field production constraints. Constant production rate could be allowed, at the beginning of field exploitation, with WHP higher than the minimum required by the surface fluid-gathering system. Further on, when WHP reaches the minimum value required because of reservoir-pressure decline, constant rate production could be switched to constant WHP. The developed algorithm can be used to compute the wellbore flow for a desired total mass rate, by computing (at the same time) the corresponding WHP. Switching to constant WHP can then be performed when the computed WHP drops below the minimum required value.

In principle, this approach would make for a more reliable coupled simulation of reservoir and wellbore flow, with more realistic modeling of well production control during the life of a geothermal field.

CONCLUSIONS

The modeling of coupled wellbore-reservoir flow is important for realistic simulation of fluid withdrawal during the exploitation of geothermal reservoirs. Coupled flow must be simulated in directional wells and in the presence of the multiple feed points often encountered in exploited geothermal fields. The DELV and F-type options presently available in TOUGH2 have limitations relative to the realistic handling of wellbore flow

in the presence of multiple feeds. First, TOUGH2 is modified to allow the use of the F-type option, with wellhead control of well production, coupled to the well on deliverability approach (DELV) for wells completed over multiple layers.

Then, subroutine GCOR is modified to allow a more reliable simulation of wellbore flow by solving mass-, momentum- and energy-conservation equations between wellbore nodes under the assumption of steady-state conditions. At each feed point, mass and energy balance equations are solved, accounting for well and reservoir contributions, and new thermodynamic conditions are determined, performing an iso-enthalpic flash calculation for given pressure, enthalpy, and composition of the mixture. Flowing P&T profiles for single and two feed points, with different combinations of thermodynamic conditions, have been simulated with the modified TOUGH2 version. Comparison with results computed by the PROFILI wellbore simulator showed consistently good reproduction of TOUGH2 results.

The developed approach can be used to control wellbore production in the presence of multiple feeds by assigning the flowing pressure at the top of production interval, as well as at the surface, thus allowing wellhead control of wellbore flow. Tests performed so far have indicated a marginal incremental increase in computing time in 3D simulations, suggesting that the approach can be safely used in field-scale simulations of geothermal reservoir exploitation.

In future work, the developed approach needs to be extended to fluid mixtures containing dissolved solids and noncondensible gases.

ACKNOWLEDGMENTS

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